INTEGRATION OF COAL-BASED PIPELINE GAS AND POWER PRODUCTION

C. L. Tsaros

Institute of Gas Technology
3424 S. State Street
Chicago, Illinois 60616

The upgrading of the energy in coal and other fossil fuels to electric energy is a well-established technology. A future technology, now being developed, will be the conversion of solid fossil fuels, such as coal and oil shale, to fluid fuels. Both private and public funds have been and are being spent to develop processes to make such conversion practical. This paper will explore the possibility of integrating a projected pipeline gas process with a conventional power plant.

PIPELINE GAS FROM COAL

The Institute of Gas Technology has studied the conversion of coal to pipeline gas for many years. Our process is the direct hydrogenation of pretreated coal to produce a gaseous effluent, which is then upgraded to pipeline gas quality. In our process about half of the coal is gasified, using most of the volatile matter and leaving a spent char as the basis for hydrogen production. The hydrogen-making step, based on the spent char, is the subject of a number of variations in making pipeline gas by coal hydrogasification.

A current process concept, which will be studied in a large pilot plant project sponsored jointly by the Office of Coal Research and the American Gas Association, bases hydrogen production on the electrothermal steam gasification of char in a fluidized bed. Figure 1 shows a simplified flow diagram of the major process features of a commercial plant based on this process (1). A hydrogen stream as such is not used. Instead, raw, hot synthesis gas containing 48% hydrogen and 37% carbon monoxide is fed to the hydrogasifier. The use of synthesis gas directly is technically feasible and saves money by eliminating the carbon monoxide conversion and carbon dioxide removal steps necessary to make a high-purity hydrogen stream. About 44% of the hydrogasifier spent char is fed to the electrothermal gasifier where it is gasified with steam, heat being provided by electricity. About 52% of the spent char is sold as by-product fuel. The fluidized electrothermal gasifier has been studied in a pilot plant at Iowa State University and will be developed on a larger scale at IGT.

Table 1 presents an economic summary of a mine mouth pipeline-gas-from-coal plant. Economic studies, carried out as part of the OCR-A.G.A. development of the IGT hydrogasification process, are based on the manufacture of 250 billion Btu/day of pipeline gas heating value. In this design a total of 17,790 tons/day of coal is required, and the total investment is $93,245,000. With coal at 16.1¢/million Btu ($4.00/ton), the 20-year average gas price is estimated at 51.1¢/million Btu of product gas heating value. Approximately 20% of the gas price is represented by purchased power at 3 mills/kWhr. This cost is based on a nearby modern power plant of the 800-MW level, a 90% load factor for the gas plants, and a 16.1¢/million Btu fuel. A charge of 1 mill is worth 3.4¢/million Btu pipeline gas.

Table 2 gives figures for the pipeline gas plant on the overall conversion of input thermal energy to product heating values.

Table 1. ECONOMIC SUMMARY FOR PIPELINE GAS PLANT THAT PERFORMS HYDROGASIFICATION OF COAL USING SYNTHESIS GAS

Product Gas	258×10^9 Btu/day, 937 Btu/SCF	
Total Investment	$93,245,000	
Coal Required	17,790 tons/day	
By-product Char	4160 tons/day	
Operating Costs, $/Year		
Coal, at 16.1¢/10^6 Btu		23,377,000
Electric Power at 3 mills/kWhr at Process Voltage		8,410,000
Other Operating Expenses		13,636,000
Total Operating Expense		45,423,000
By-product Credit		(7,030,000)
Char and Pretreatment Fines	5,398,000	
Sulfur	1,632,000	
	7,030,000	
Net Operating Expense		38,393,000
Return Plus Federal Income Tax, 20-yr Average		4,867,000
		43,260,000

20-yr Average Price of Gas – 51.1¢/10^6 Btu

Table 2. PIPELINE GAS PLANT CONVERSION EFFICIENCY

	In, 10^6 Btu/hr			Out, 10^6 Btu/hr
Coal	18,369		Product Gas	10,776
Electricity	1,162		By-Product Char	4,006
Total	19,531			14,782
Overall Eff, %		75.6		
Coal	18,369			
Fuel for Electric Power at 40% Eff	2,910			
Total	21,279			14,782
Overall Eff, %		69.5		

If the input electric energy to the gasifier is included, the overall efficiency for the gas plant is 75.6%. However, if the fuel energy required to produce the electricity at 40% efficiency is counted as an input, the overall fuel conversion efficiency drops to 69.5%. Power requirements for the pipeline gas plant are summarized in Table 3.

Table 3. PIPELINE GAS PLANT POWER SUMMARY

	kW
Electrothermal Gasifiers, Purchased Power	340,120
Electric Motors, Purchased Power	15,340
Steam Turbine Drives Powered by Heat Recovery Steam	47,330
Total Power	402,790

The electrothermal gasifier consumes 84% of the total plant power, of which 88% is purchased. Of the total motive power, 76% is supplied by steam turbines driven by steam generated from waste heat that otherwise would be rejected to cooling water.

Table 4 summarizes the heat recovery plus process cooling for a pipeline gas plant. The table shows the amounts and temperature levels of heat requirements and where there might be possibilities of energy interchange with an adjacent power plant. Heat going to cooling water could be used to preheat the feedwater for the power plant turbine in the low-temperature part of the cycle. Instead of using it to generate low-temperature steam, the 870 million Btu/hr of hydrogasifier effluent, in cooling from 750° to 280°F, could be used to heat the turbine feedwater at the higher temperature. The required regeneration steam, 796,000 lb/hr, could then be extracted from the power plant turbine at 100 psia, thus saving the heat going to cooling water.

ELECTRIC POWER GENERATION

Integrated power production and industrial operation has been previously suggested. A recent paper presents a general discussion of the various aspects of this question (3). The present paper discusses the potential for integration of pipeline gas plants and power plants. This presentation is an initial look at a specific case and is designed to show the advantages of joint operation. We have not estimated all the economic effects nor optimized the conditions for joint pipeline gas and power production versus separate operation. However, we made calculations of the effect of energy interchange on the power plant cycle.

Figure 2 shows a simplified drawing of a typical modern power plant cycle. The efficiency of such a cycle for a given boiler efficiency is raised by decreasing the heat going to cooling water per kWhr of energy generated. This is accomplished by the expansion of most of the steam to a very low pressure, 1-2 in. Hg, followed by condensation. Intermediate extraction of steam from the turbine raises the temperature of the feedwater to the 500°-550°F level. Eight feedwater heaters may be used in a typical system, with progressively higher extraction steam and feedwater temperatures. This system produces a higher efficiency than a nonextraction system because, although the extracted steam does not expand to the lowest pressure, the heat that would otherwise go to cooling water is recovered to heat the boiler feedwater.

Table 4. SUMMARY OF PIPELINE GAS PLANT HEAT RECOVERY AND COOLING

Heat Source	Temperature Range	Service	10^6 Btu/hr
Pretreatment Reactor	750°F fluidized bed	Generate process steam, 1200 psig, 510°F	624
		Generate turbine steam, 1200 psig, 570°F	254
		Preheat boiler feedwater, 525°-570°F	84
Hydrogasifier Effluent	1200°-750°F	Superheat reaction steam, 570°-700°F	133
		Superheat turbine steam, 570°-900°F	109
		Preheat high-pressure boiler feedwater, 320°-525°F	334
Hydrogasifier Effluent	750°-280°F	Preheat feedwater and generate low-pressure regeneration steam, 100°-238°F	870
Hydrogasifier Effluent	280°-260°F	Preheat high-pressure boiler feedwater, 60°-100°F	60
Methanation Effluent	900°-300°F	Preheat high-pressure boiler feedwater, 100°-325°F	325
Methanation Effluent	300°-100°F	Heat to cooling water	247
Hot Carbonate Regeneration Steam Condenser-Cooler	230°-100°F	Heat to cooling water	870
Fired Superheater	--	Superheat reaction steam, 700°-1200°F	315

Methods to rapidly determine the improvement in heat rate resulting from feedwater heating have been published (2). Thus, for initial steam conditions of 3000 psig at 1000°F, with expansion to 2 in. Hg, the nonextraction input to steam heat at 100% turbine efficiency is 7730 Btu/kWhr. With an average turbine efficiency of 87% and a boiler efficiency of 90%, the overall heat rate will be 9870 Btu/kWhr and overall efficiency will be 34.6%. However, with extraction feedwater heating to 500°F (Figure 2), the heat rate is reduced to about 8500 Btu/kWhr, corresponding to the 40% overall efficiency typical of modern power plants.

JOINT PIPELINE GAS AND ELECTRIC POWER GENERATION

If all or most of the turbine feedwater preheat can be obtained from waste heat in an adjacent pipeline gas plant, then the steam that would otherwise be extracted can be expanded to the lowest pressure, 1-2 in. Hg, with an increase in power output per Btu of boiler input to the steam cycle.

Calculations have been made for two such cases, with the resultant heat rates based on the above boiler and turbine efficiencies. In the first case, Figure 3, the turbine feedwater absorbs low-temperature heat from methanation reactors, the regeneration tower steam condenser, and waste heat that otherwise would be used to generate low-pressure regeneration steam for hot carbonate scrubbing units. The required low-pressure steam is then obtained by extraction from the power plant turbine at 100 psia. Waste heat recovered in the gas plant to generate steam for individual turbine drives is not used to preheat the feedwater for the large power plant in this case. To complete the preheating of this feedwater to 500°F, some extraction is necessary.

The power cycle assumed for these calculations is the expansion of 3000 psig, 1000°F steam to 700 psia followed by reheating to 1000°F. Part of the 700-psia steam is used for the heating prior to reheat. Except for the extraction of 796,000 lb/hr steam, as noted above, at 100 psia for use in the gas plant, most of the steam then expands to 2 in. Hg. The overall efficiency for the power plant with this system is 43.0%; the heat rate is 7940 Btu/kWhr.

If no turbine steam is generated in the pilot plant, this heat can then be used to raise the power plant turbine feedwater to approximately 500°F. In the scheme shown in Figure 4, there is no extraction for feedwater preheat, but 100-psia steam is again extracted for use in the gas plant. At these conditions, the overall efficiency is 46.7% and the heat rate is 7310 Btu/kWhr. However, in the second case, 402,800 kW must be sent to the gas plant compared to 355,460 kW when part of the motive power is provided by individual steam turbines in the gas plant. In an integrated operation there may be capital cost advantages in having all the power generated in a very large unit because of economies of scale. However, there would be a charge for the added 47,330 kW sent to the gas plant, which reduces the effect of savings in the capital and fuel components of power cost. The exact cost would have to be derived from the total operation as influenced by the improvements resulting from the integration of gas-electric operation.

ADVANTAGES OF INTEGRATED OPERATION

The effect of integrated operation is to increase the overall efficiency of coal conversion to pipeline gas plus electricity for sale from 64.8% for separate operation to 66.5% for joint operation.

A single cooling-water facility could be used for both gas and electric plants. Superheating of the process steam for the gas plant (315 million Btu/hr) can be carried out more economically in the power plant boiler (6 billion Btu/hr level) as an incremental increase in the superheater section than as a separately fired superheater. Cooling-water requirements for the gas plant are greatly reduced.

This, plus the economies of scale, can save several million dollars in offsite costs.

Since the gas plant operates on a 90% annual stream factor, the load factor for the power plant will be improved over the more typical 60% industry average. This improvement, plus the improved fuel economy, could reduce power costs on the order of 1 mill/kWhr. Part of the basis for the 3-mill power cost used in Table 1 is the high load factor resulting from joint operation.

Spent char from the gas plant can be used as fuel for the power plant. A high-sulfur coal, a liability in power generation, can be an asset in hydrogasification. During hydrogasification, most of the sulfur is converted to H_2S, from which the sulfur can be recovered and sold as a by-product. In the pipeline gas plant design used as a basis for this study, a 4.4% sulfur coal yields a char containing 1.7% sulfur. To increase the production of char, the percentage conversion during hydrogasification can be decreased, raising the coal throughput for constant gas production. More hydrogen can then be obtained from the coal, which reduces that obtained from the synthesis gas, which, in turn, gives a lowered gas price. The degree of coal conversion to gas would have to be optimized in relation to the gas-electric operations.

Not only the degree of conversion, but the sizes of the gas and the power plants would need to be optimized. A combination gas-electric utility interested in a pipeline-gas-from-coal plant would also find the study of integrated operation of interest.

Integrated gas-electric operations would involve regulated industries, with similar rates of return. This is not true, however, for joint power plant-industrial operation, where the differing rates of return and depreciation cause more complicated cost allocation.

As a result of potential savings in gas plant investment and power charges, it appears that the price of gas can be reduced by several cents per million Btu compared to completely separate operation.

In summary, the following advantages are possible for an integrated operation:

1. Increased power plant efficiency and load factor.
2. Reduction of investment for the pipeline gas plant through economies of scale by combining facilities for power generation, steam superheat, and cooling-water facilities with those of the power plant.
3. Lowered pipeline gas price.
4. Production of low-sulfur power plant fuel as a by-product of the pipeline gas plant, thus reducing air pollution problems when high-sulfur coal is used.

ACKNOWLEDGMENT

The work reported herein is under the cosponsorship of the American Gas Association and the U.S. Department of the Interior, Office of Coal Research. Permission of the sponsors to present this paper is greatly appreciated.

LITERATURE CITED

1. Knabel, S. J. and Tsaros, C. L., "Process Design and Cost Estimate for a 258 Billion Btu/Day Pipeline Gas Plant – Hydrogasification Using Synthesis Gas Generated by Electrothermal Gasification of Spent Char," Office of Coal Research Report. Chicago: Institute of Gas Technology, 1967.

2. Salisbury, J. K., "A Short Cut to Turbine Cycle Heat Rates—Part 1," Power 87, 664-67, 709b, 709c (1943) October; Part II, ibid. 87, 734-37 (1943) November.

3. Trommershausen, W. E. and Rossie, J. P., "Integration of Power Production and Industrial Operation." Paper presented at the Symposium on Fossil Hydrocarbon and Mineral Processing, 62nd Annual Meeting, American Institute of Chemical Engineers, Salt Lake City, Utah, May 21-24, 1967.

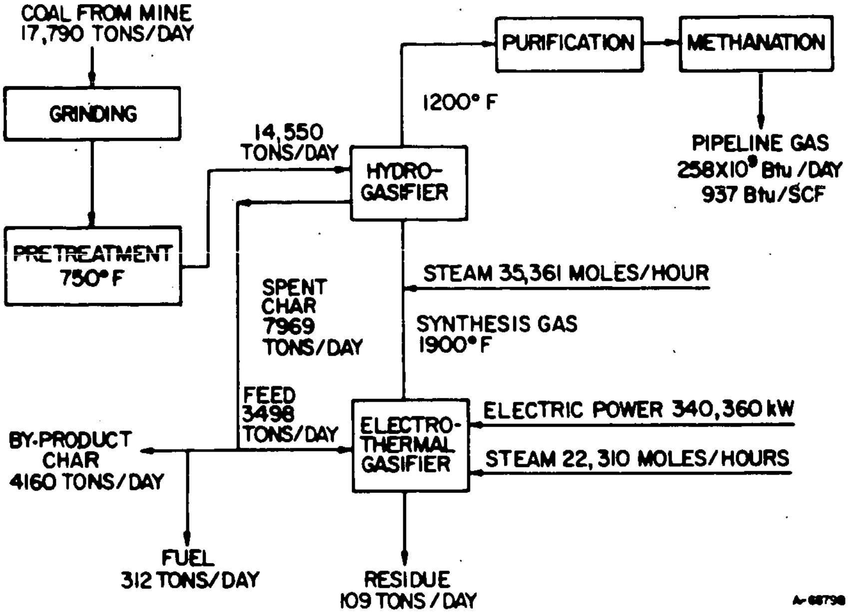

Figure 1. 258 Btu/DAY PIPELINE GAS BY HYDROGASIFICATION OF COAL USING SYNTHESIS GAS GENERATED BY ELECTROTHERMAL GASIFICATION OF SPENT CHAR

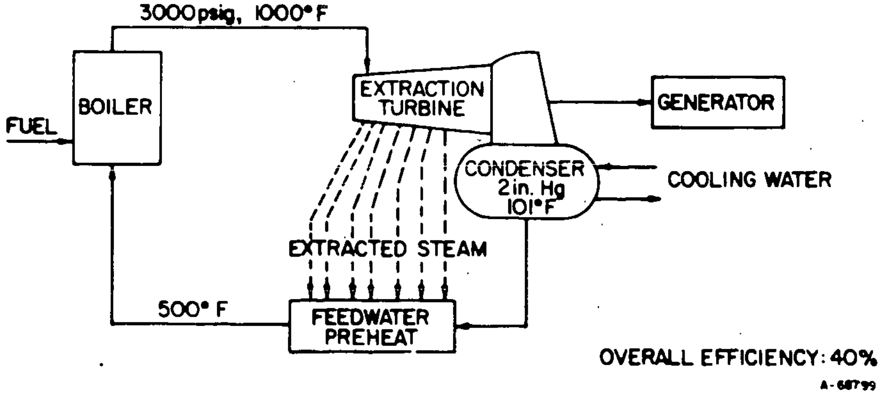

Figure 2. SIMPLIFIED FLOW DIAGRAM OF CONVENTIONAL POWER PLANT

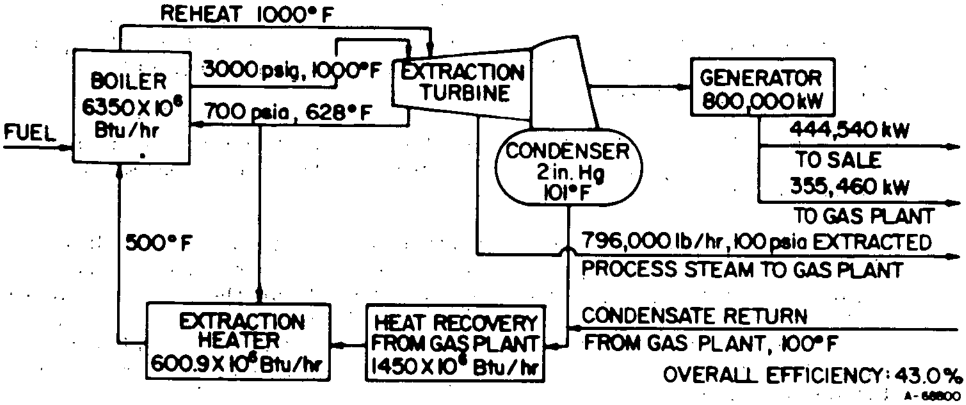

Figure 3. POWER PLANT CYCLE FOR JOINT OPERATION WITH PIPELINE GAS PLANT WASTE HEAT STEAM USED FOR TURBINE DRIVE IN GAS PLANT

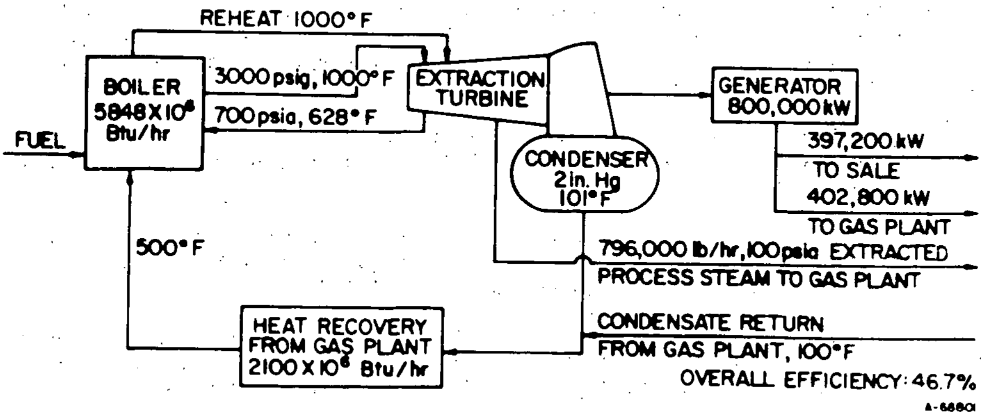

Figure 4. POWER PLANT CYCLE FOR JOINT OPERATION WITH PIPELINE GAS PLANT
(No Turbine Drives in Gas Plant)